Cost-minimized combinations of wind power, solar power and electrochemical storage, powering the grid up to 99.9% of the time

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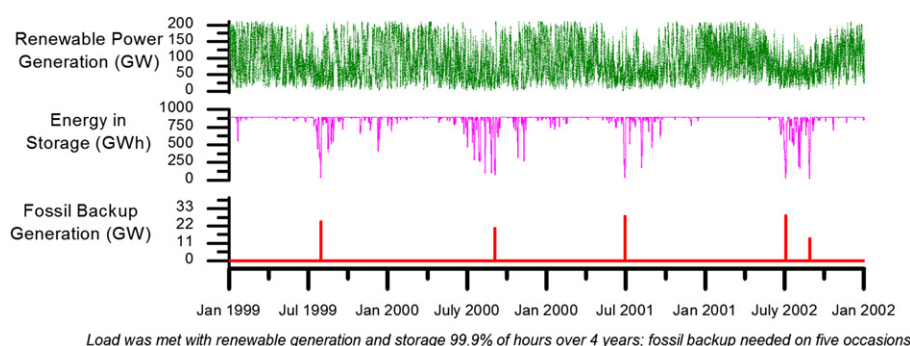[d] Energy and Environmental Policy Program, College of Engineering, University of Delaware, Newark, DE 19716, USA
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HIGHLIGHTS

► We modeled wind, solar, and storage to meet demand for 1/5 of the USA electric grid.
► 28 billion combinations of wind, solar and storage were run, seeking least-cost.
► Least-cost combinations have excess generation (3× load), thus require less storage.
► 99.9% of hours of load can be met by renewables with only 9–72 h of storage.
► At 2030 technology costs, 90% of load hours are met at electric costs below today's.

GRAPHICAL ABSTRACT

Load was met with renewable generation and storage 99.9% of hours over 4 years; fossil backup needed on five occasions

ARTICLE INFO

ABSTRACT

We model many combinations of renewable electricity sources (inland wind, offshore wind, and photovoltaics) with electrochemical storage (batteries and fuel cells), incorporated into a large grid system (72 GW). The purpose is twofold: 1) although a single renewable generator at one site produces intermittent power, we seek combinations of diverse renewables at diverse sites, with storage, that are not intermittent and satisfy need a given fraction of hours. And 2) we seek minimal cost, calculating true cost of electricity without subsidies and with inclusion of external costs. Our model evaluated over 28 billion combinations of renewables and storage, each tested over 35,040 h (four years) of load and weather data. We find that the least cost solutions yield seemingly-excessive generation capacity—at times, almost three times the electricity needed to meet electrical load. This is because diverse renewable generation and the excess capacity together meet electric load with less storage, lowering total system cost. At 2030 technology costs and with excess electricity displacing natural gas, we find that the electric system can be powered 90%–99.9% of hours entirely on renewable electricity, at costs comparable to today's—but only if we optimize the mix of generation and storage technologies.

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1. Introduction

What would the electric system look like if based primarily on renewable energy sources whose output varies with weather and sunlight? Today's electric system strives to meet three requirements: very high reliability, low cost [1], and, increasingly since the 1970s, reduced environmental impacts. Due to the design constraints of both climate mitigation and fossil fuel depletion, the possibility of an electric system based primarily on renewable energy is drawing increased attention from analysts. Several studies (reviewed below) have shown that the solar resource, and the wind resource, are each alone sufficient to power all humankind's energy needs. Renewable energy will not be limited by resources; on the contrary, the below-cited resource studies show that a shift to renewable power will increase the energy available to humanity. But how reliable, and how costly, will be an electric system reliant on renewable energy? The common view is that a high fraction of renewable power generation would be costly, and would either often leave us in the dark or would require massive electrical storage.

Here we model the hourly fluctuations of a large regional grid, PJM Interconnection, in order to answer these questions. PJM is a large Transmission System Operator (TSO) in the eastern United States. It is located geographically in Fig. 1, and described in more detail in Appendix A. To obtain a multi-year run with constant system size we analyze calendar years 1999–2002, before its recent growth, when PJM managed 72 GW of generation, with an average load of 31.5 GW$_a$ [2].

To evaluate high market penetration of renewable generation under a strong constraint of always keeping the lights on, we match actual PJM load with meteorological drivers of dispersed wind and solar generation (Fig. 1) for each of the 35,040 h during those four years. We created a new model named the Regional Renewable Electricity Economic Optimization Model (RREEOM). Our model is constrained (required) to satisfy electrical load entirely from renewable generation and storage, and finds the least cost mix that meets that constraint. The model is computationally-constrained, so we did not include additional computing-intensive considerations, such as how much additional transmission is optimum, or reliability issues not related to renewable resource fluctuations.

2. Prior studies

We do not find the answers to the questions posed above in the prior literature. Several studies have shown that global energy demand, roughly 12.5 TW increasing to 17 TW in 2030, can be met with just 2.5% of accessible wind and solar resources, using current technologies [3–5]. Specifically, Delucci and Jacobson pick one mix of eight renewable generation technologies, increased transmission, and storage in grid integrated vehicles (GIV), and show this one mix is sufficient to provide world electricity and fuels. However, these global studies do not assess the ability of variable generation to meet real hourly demand within a single transmission region, nor do they calculate the lowest cost mix of technologies.

Ekren and Ekren analyzed a small-scale system with batteries, PV, wind turbines, and auxiliary power [6]. The study assumes near-constant load (for communications), calculates only an energy capacity for the batteries and not power limits, and optimizes the configuration for minimum capital cost, not minimum total cost. Unfortunately, Ekren and Ekren only report their optimized system cost and area of solar and wind rotor as well as battery size so it is difficult to analyze these results. In a real grid, we must satisfy varying load, and with high-penetration renewables, charging and discharging storage will at times be limited by power limits not just by stored energy. More typical studies combining wind and solar do not seek any economic analysis and/or do not look at hourly match of generation to load (e.g. Markvart, 1996).

Hart and Jacobson determined the least cost mix for California of wind, solar, geothermal and hydro generation [7]. Because their mix includes dispatchable hydro, pumped hydro, geothermal, and solar thermal with storage, their variable generation (wind and photovoltaic solar) never goes above 60% of generation. Because of these existing dispatchable resources, California poses a less challenging problem than most areas—elsewhere, most or all practical renewable energy sources are variable generation, and dedicated storage must be purchased for leveling power output. We cannot draw general conclusions from the California case's results—for example, one might plausibly infer from this study that it is possible to have a power system with 60% variable generation, but not a higher fraction; or, we might conclude that a grid based exclusively on variable generation would require prohibitively expensive amounts of storage.

We can also compare our model with the HOMER micropower optimization model [8], which takes hourly load and resource data and calculates the most cost effective mix of generation. Much like HOMER, the present work employs a more valid storage cost model than other studies, because it distinguishes cost per MWh (cost per stored energy unit) from cost per MW (cost per power transfer rate). The difference between our study and HOMER is that we examine a regional power system, whereas HOMER has been used primarily for small isolated grids such as islands or single residences or buildings. One of our main objectives is to incorporate the power-leveling effects of meteorological and resource diversity on a regional scale.

3. Enough power to meet load

Current electric power systems use fossil fuels as a form of stored energy, burning fuel at variable rates to generate power matched to fluctuating power demand. The operating principle of fossil generation is "burn when needed", a principle simple enough that it could be followed without computers, digital high-speed communications, or weather forecasting—precisely the conditions when today's electric system was created, early in the 20th century.

The ability to reliably meet load will still be required of systems in the future, despite the variability inherent in most renewable resources. However, a review of existing literature does not find a satisfactory analysis of how to do this with variable generation, nor on a regional grid-operator scale, nor at the least cost. We need to solve for all three.

In order to manage variable generation, there are four known options: geographical expansion, diversifying resources (e.g. solar plus wind), storage, and fossil backup. All four are employed in this study.
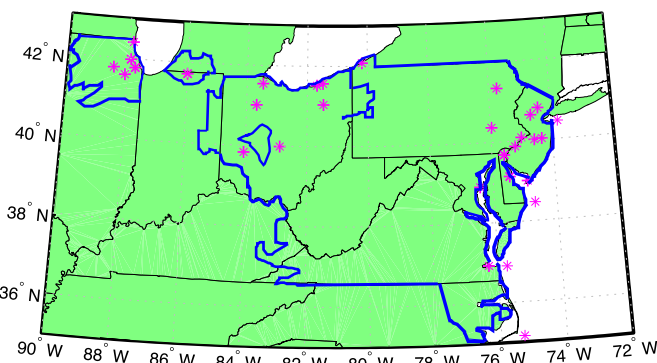
Fig. 1. A map showing the outlines of the current PJM system (blue line) and of the inland and offshore meteorological stations used for the wind data (pink asterisks). (For interpretation of the references to color in this figure legend, the reader is referred to the web or PDF version of this article.)

The first option is to geographically distribute generation. Wind from geographically dispersed sites (greater than 1000 km) provides more consistent power output than generation at nearby locations with similar weather patterns [9–11]. The current study calculates the time diversity of generation from geographically dispersed sites' actual hourly weather (Fig. 1).

The second option, diversifying sources, can similarly level power production, as has been shown in prior studies of wind and solar [12,13] for a wider range of renewables [4,7]. These prior studies showed that combining more diverse renewable resources produced more level power.

Storage is the third option, typically the most costly. Storage can fill in supply gaps as well as absorb excess production, and since storage responds quickly, it can adjust for rapid changes in wind or solar output. Denholm et al. employed existing spatially dispersed wind farms in the Midwest along with fixed amounts of storage with the goal of providing level power output, like a baseload thermal plant [14]. But, the real grid management problem is not to simulate a single baseload plant by creating constant output; rather, the problem is to meet fluctuating load reliably with fluctuating generation, for an entire grid.

A fourth option is to use existing fossil generation for backup. Although this reintroduces pollution into the system and can only produce to meet shortfall, not absorb excess electricity, it takes advantage of existing generation plants, thus costing only fuel and operations not new plant investment. We model fill-in power from fossil, not hydro or nuclear power. Hydropower makes the problem of high penetration renewables too easily solved, and little is available in many regions, including PJM. We do not simulate nuclear for backup because it cannot be ramped up and down quickly and its high capital costs make it economically inefficient for occasional use. For scenarios in which backup is used rarely and at moderate fractions of load, load curtailment is probably more sensible than fossil generation. This could be considered a fifth mechanism, but for simplicity we here conservatively do not assume load management but fill any remaining gaps of power with fossil generation.

4. Model parameters

For each of the three power generation technologies—solar PV, offshore wind, and inland wind—our input parameters set a maximum, up to actual resource limits in PJM, and the REEOM model will try all values from 0 to the maximum, seeking optimum combinations. The model was run for three storage technologies: centralized hydrogen, centralized batteries, and grid integrated vehicles (GIV), the latter using plug-in vehicle batteries for grid storage when they are not driving (also called "vehicle to grid power" or V2G) [15,16]. Wind and solar are parameterized as GW capacity, storage is parameterized as GW throughput and GWh energy storage capability. Storage is additionally characterized by losses in storing or releasing electricity, plus the standby losses while sitting idle. The models for each individual technology are relatively simple. For example, we used NREL's program PVWATTS for the solar power hourly output, and used a typical commercial wind tubine's power curve to calculate the hourly wind power output with the wind speed input from NOAA buoys. The method is discussed in more detail in in "Technologies" section of the Appendix. The purpose of this study is not to model and validate each individual technology in detail, rather we use accepted and simple models for each technology, so we can focus on capturing the varying times of generation and load, and how much storage is needed to level variable generation.

When running the simulation, for each hour, weather is used to determine that hour's power production. If renewable generation is insufficient for that hour's load, storage is used first, then fossil generation. During times of excess renewable generation, we first fill storage, then use remaining excess electricity to displace natural gas. When load, storage and gas needs are all met, the excess electricity is "spilled" at zero value, e.g. by feathering turbine blades. See Fig. 2 for more on the model's operation.

In calculating the cost of each combination, we calculate true cost of electricity without subsidies. In the case of renewable generation, we exclude current subsidies from the Federal and State governments. For fossil power, we add in pollution's external costs to third parties; these are not included in market price, but are borne by other parties such as taxpayers, health insurers, and individuals. Here they are included in the cost of electricity (see Appendix, "Cost of Electricity"). For the cost of renewable energy and storage, we used published costs for 2008, and published projections for 2030, all in 2010 dollars. For example, projected capital costs for wind and solar in 2030 are roughly half of today's capital costs but projected operations and maintenance (O&M) costs are about the same (references and explanations of costs are in Tables 1 and 2). The 2030 cost projections assume continuing technical improvements and scaleup, but no breakthroughs in renewable generation nor storage technologies. For fossil fuels, we use prices plus external costs today, without adjustments for future scarcity, pollution control requirements, nor fuel shifts. Our cost model is detailed in Appendix, "Cost of Electricity", and as we will show (in Table 4), a simple validation of the cost model is that unsubsidized renewable energy costs, for 2008 cost input parameters, are consistent with actual renewable power costs in recent years. We do not include load growth because we are comparing the optimum point under differing cost parameters, not projecting to the power system of 2030. These assumptions have the advantage that simple and transparent inputs to a complex model make relationships clearer.

The costs being minimized included the expenses of financing, building and operating solar, wind and storage, expressed in cents per kWh delivered to load. The hours not covered by the system have an additional cost for fossil electricity; this is tabulated to compute cost per kWh but it was not part of the cost minimization algorithm.

Separate simulations were performed for each of the three storage technologies, for 2008 costs and for 2030 costs, and for three coverage requirements (30%, 90%, and 99.9% of hours) making a total of 18 RREEOM runs. The coverage requirement is a constraint on the model, that is, any one tested combination of generation types and storage must meet all load that fraction of hours, or we do not evaluate it for cost. These three percentage requirements allow us to evaluate the practicality of a range of renewable penetrations. They are not system reliability targets—as noted subsequently, existing fossil is assumed to cover part of the load for hours during which renewables were not sufficient. That is, for example, our 99.9% coverage target does not imply that the commercial electric reliability requirement of 99.97% has been reduced, only that the last fraction of a percent above our 99.9% would have to be covered by existing fossil generation (or demand management, etc.). Each of the 18 REEOM simulations evaluated about 1.6 billion combinations of technologies to pick the least cost mix that met each coverage constraint.

We simplify our grid model by assuming perfect transmission within PJM (sometimes called a "copper plate" assumption), and no transmission to adjacent grids. We also simplify by ignoring reserve requirements, within-hourly fluctuations and ramp rates; these would be easily covered with the amount of fast storage contemplated here. In addition, we assume no preloading of storage from fossil (based on forecasting) and no demand-side management. Adding transmission would raise the costs of the renewable systems calculated here, whereas using adjacent grids, demand management, and forecasting all would lower costs. We judge the latter factors substantially larger, and thus assert
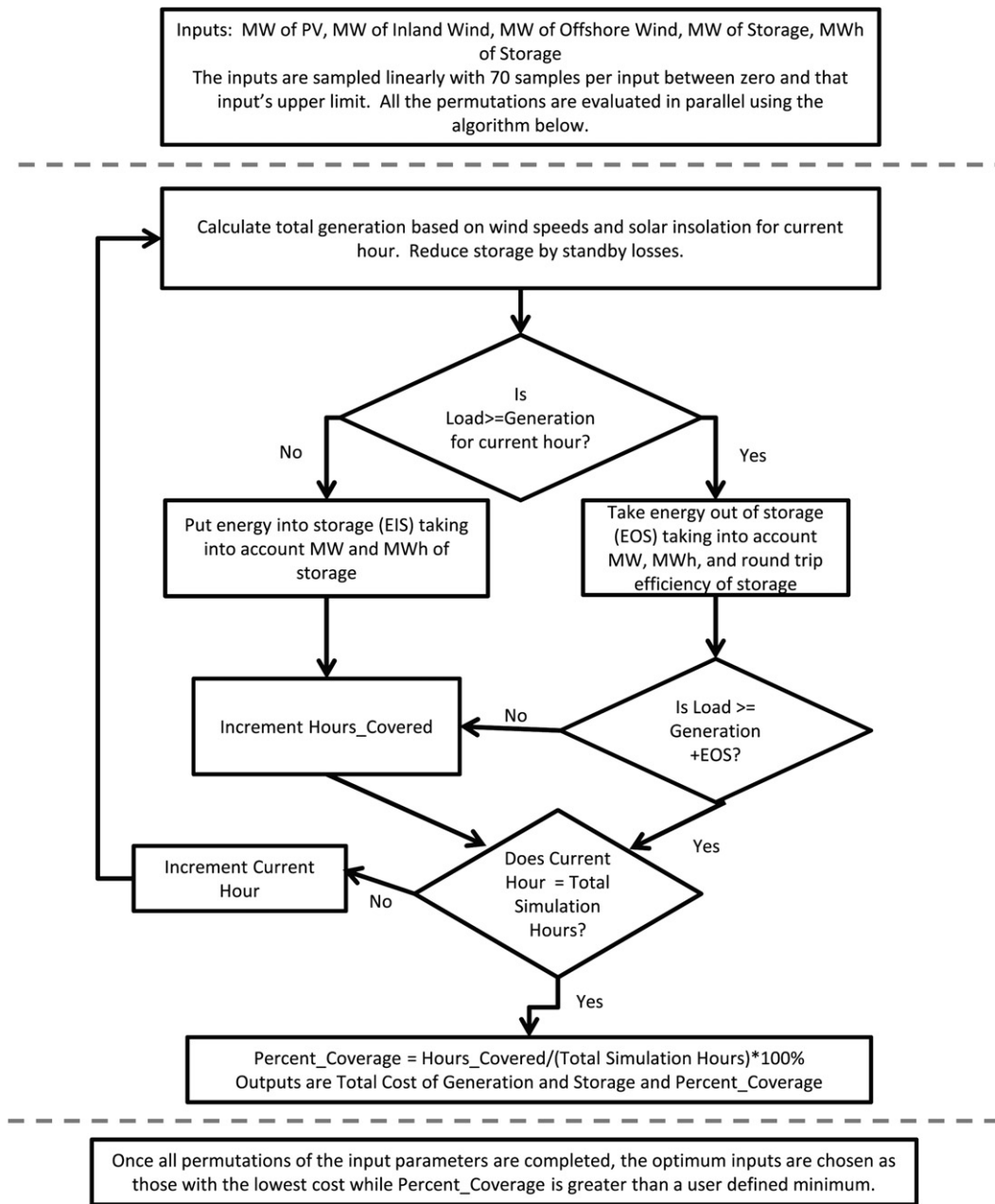
Fig. 2. Flow chart of RREEOM.

(without calculation) that the net effect of adding all these factors together would not raise the costs per kWh above those we calculate below.

In order to realistically simulate generation, we use insolation and wind data from DOE and NOAA for each hour being modeled. To start with a realistic amount of storage, we run for a 9 month initialization period to fill storage based on actual generation and loads. Methods and input values are described in the Appendix.

Our study has some limitations. PJM is a large system operator; a smaller region would experience less smoothing effect from connecting wind across its region. We discounted future renewable generation at 12%, did not project any increase in fossil fuel prices, eliminated tax subsidies for renewables but not traditional generation, and did not project any technology breakthroughs for renewables, all of which raise the comparative cost of renewable power.

5. Results and discussion

Table 3 shows the results from three of the 18 simulations, for storage using GIV and 2030 technology costs for all three coverage constraints of 30%, 90% and 99.9%. For other storage technologies and 2008 technology costs, the relationships are similar to those shown in Table 3 but quantitative results are not (see Table 8 for all cases). Results in Table 3 are shown in capacity installed (in GW), and energy generated or released from storage in average power or GW_a. (GW_a is equivalent to $GWh\ y^{-1}$ divided by $8760\ h\ y^{-1}$; using GW_a for average power rather than GWh for energy per year makes it easier to compare among capacity, production, and load.) The actual PJM system generation capacity and load are shown on the bottom line. PJM for the years of our study had 72 GW of generation capacity, which was 230% of its 31.5 GW_a average load.

Table 1
Input parameters 2008 values.

Technology	Capital cost per energy storage ($/kWh)	O&M cost per energy storage throughput ($/MWh)	O&M net present cost[a] ($/MWh)	Lifetime of energy equipment (years)	Capital power cost ($/kW capacity)	O&M cost per unit of power capacity ($/kW/year)	O&M net present cost[a] for 20 years ($/kW)
Photovoltaics	0	N/A	0	N/A	6350[b]	12.3[b]	91.6
Offshore Wind	0	N/A	0	N/A	4050[b]	94.0[b]	702
Inland Wind	0	N/A	0	N/A	2022[b]	31.8[b]	238
GIV	31.8[c,f]	247[c,g]	1847	15[d]	100[c,h]	0[c,i]	0
Hydrogen	28.1[e,j]	0[e]	0	20[e,j]	1683[e,k]	27.5[e,k]	206
Central Batteries (Lithium titanate)	318[d]	0[d]	0	15[d]	703[d]	12.3[d]	91.6

Technology	Lifetime power equipment (years)	Energy cost for 20 years ($/kWh)	Upper energy limit of resource (GWh)	Power cost for 20 years ($/kW)	Upper power limit of resource (GW)	Round trip efficiency (fraction)	Storage loss over time (fraction lost per hour)
Photovoltaics	30[l]	N/A	N/A	4294[l]	186[m]	N/A	N/A
Offshore wind	30[l]	N/A	N/A	3168[l]	158[n]	N/A	N/A
Inland wind	30[l]	N/A	N/A	1507[l]	132[o]	N/A	N/A
GIV	50[p]	44.9	382[q]	40	239[q]	0.81[r]	8.33E-05[s]
Hydrogen	20[t]	28.1	N/A	1889	∞	0.438[t]	1.50E-08[u]
Central batteries (lithium titanate)	15[v]	424	N/A	1060	∞	0.81[r]	8.33E-05[s]

[a] Net present costs were determined using a 12% discount rate over 20 years.

[b] Delucchi and Jacobson [3].

[c] Kempton and Tomic [15].

[d] Burke and Miller [18].

[e] Steward [19].

[f] The energy cost for the GIV batteries is assumed to be 10% of the cost of standalone Li-ion batteries because of increased cycling, based on our estimate + $400 divided by the battery size (24 kWh, the size of the battery in the Nissan Leaf) on board vehicle costs, which will last the ~15 year life of vehicle, from Kempton and Tomic [15] Table 5 parameter Cc.

[g] This calculation is taken from Table 5 and equations (13) and (15) of [15]. For LiIon, the lifetime (L_C) is assumed to be 5000 cycles [18]. E_s is assumed to be 24 kWh which is the size of the battery pack (equivalent to Nissan Leaf). Also, the CYP is the cycles per year which is assumed to be 10. This is updated after the optimum is reached to a more realistic value. The value is then multiplied by 30% because the depth of discharge is less than 100%, degrading the batteries less. $c_d = \frac{c_{bat}}{L_C * E_S} * CPY * 30\% = \frac{\$247.25}{\text{MWh year}}$

[h] Capital power costs for GIV were calculated assuming it would cost $1500 for the building connections for a 15 kW battery, which converts to $100,000/MW, with a typical building lifetime of 50 years. From Kempton and Tomic [15], Table 5.

[i] O&M power costs for GIV are considered to be zero because there is no additional maintenance due to GIV power. Maintenance is not increased due to power capability for GIV, it is calculated as proportional to energy in a separate column. The maintenance costs for controls that are particular to the GIV system, not otherwise required for the vehicle, are considered negligible.

[j] The energy cost is the cost of the steel tank, based on how many kg of hydrogen the tank can hold [20] which is converted to a $/MWh equivalent using the HHV of hydrogen. It is assumed that the steel tanks last 20 years.

[k] The power cost is assumed from the capital cost of the solid oxide fuel cell (SOFC) system and electrolyzer system taking into account the replacement cost of the stack is 30% after ten years (this replacement cost is also discounted at 10 years out). It is assumed that the power systems will last 20 years if this stack replacement is performed. A SOFC was chosen instead of a proton exchange membrane fuel cell because of the lower cost and higher efficiency. The high operating temperature eliminates the need for precious metals, thus leading to lower cost, and the activation energy decreases, thus leading to higher efficiency. This is in contrast to most transportation applications where SOFC cannot work because of low power density.

[l] Delucci and Jacobson [3].

[m] This is calculated by scaling up a recent study of capacity potential of south facing rooftop in Newark, DE [21] and extrapolating by population to the PJM region.

[n] This is obtained for the PJM region by Baker [22]. For 2008 it is assumed that only the turbines out to 60 m water depth are available.

[o] This is obtained for each state from NREL's Wind Powering America Study [23] and then multiplied by the percentage of each state in PJM as shown in the Model Parameters section. In an NREL capacity study wind sites with less than a 30% bulk capacity factor were discarded, so for an inland wind site to be considered for this simulation it had to meet the same criterion.

[p] The power electronics are mostly considered a part of the regular operation of the vehicle. The only additional electronics are the electronics used to discharge energy back to the grid. Lifetime is considered to be 50 years.

[q] We will limit availability of GIV storage based on the vehicle fleet. Although it would make sense to discount the fleet by the number who we guess might be participating, or also the percentage of EVs and plug-in hybrids available, here we assume that 100% of the count of light vehicles in 2002 PJM are available. This is an upper resource limit. The total vehicle fleet per state is from NHTS 2009 survey [24]. 15 kW of storage per vehicle is assumed just as in the cost calculation for GIV.

[r] Lund and Kempton [25].

[s] Chen et al. [26].

[t] Steward [20].

[u] Assumed 6.35 mm thick 316 stainless steel at 51.7 MPa at 25 °C [27].

[v] Burke and Miller [18].

Consider first the power capacity, the leftmost 3 numeric columns in Table 3. As we move from requiring renewable power to meet load 30% of hours to 90%, then 99.9% of hours, the capacity of renewable generators increases and the diversity of renewable resources increases. For example, at 30%, only the least expensive renewable, inland wind, is used. But to meet 99.9%, significant amounts of all three generation resources are represented, including higher cost offshore wind and solar; total generation capacity is over three times that of the current system. Counter-intuitively, when we increase the requirement from 90% to 99.9%, less storage and significantly less fossil backup capacity are needed. This is because, to meet 99.9% of hours, more renewable generation is required from more diverse sources.

The energy columns of Table 3 show that the 30% case is rather different in generated energy from the higher levels of coverage. To cover 30% of hours with renewables, we generate about equal amounts of renewable energy and fossil energy, the sum approximately matching the total need for electricity. That is, 30% coverage is roughly the equivalent of producing 50% of energy (for the given GIV storage case), with very little excess generation. By contrast, for 90% or 99.9% of hours, the GW$_a$ generated exceeds the electrical energy need of PJM by factors of about 2× and 3×, respectively!

Table 2
Input parameters 2030 values.

Technology	Capital cost per energy storage ($/kWh)	O&M cost per energy storage throughput ($/MWh)	O&M net present cost[a] ($/MWh)	Lifetime of energy equipment (years)	Capital power cost ($/kW capacity)	O&M cost per unit of power capacity ($/kW/year)	O&M net present cost[a] for 20 years ($/kW)
Photovoltaics	0	N/A	0	N/A	2848[b]	12.3[b]	91.6
Offshore wind	0	N/A	0	N/A	2128[b]	94.0[b]	702
Inland wind	0	N/A	0	N/A	1202[b]	31.8[b]	238
GIV	19.2[c,f]	106[c,g]	791	15[d]	100[c,h]	0[c,i]	0
Hydrogen	11.2[e,j]	0[e]	0	20[e,d]	737[e,k]	12.2[e,k]	91.4
Central batteries (lithium titanate)	192[d]	0[d]	0	15[d]	411[d]	12.3[d]	91.6

Technology	Lifetime power equipment (years)	Energy cost for 20 years ($/kWh)	Upper energy limit of resource (GWh)	Power cost for 20 years ($/kW)	Upper power limit of resource (GW)	Round trip efficiency (fraction)	Storage loss over time (fraction lost per hour)
Photovoltaics	30[l]	N/A	N/A	1958[l]	186[m]	N/A	N/A
Offshore wind	30[l]	N/A	N/A	1886[l]	248[n]	N/A	N/A
Inland wind	30[l]	N/A	N/A	960[l]	132[o]	N/A	N/A
GIV	50[p]	26.7	891[q]	40.0	239[q]	0.81[r]	8.33E-05[s]
Hydrogen	20[t]	11.2	N/A	828	∞	0.609[t]	1.50E-08[u]
Central batteries (lithium titanate)	20[v]	256	N/A	503	∞	0.81r	8.33E-05[s]

[a] Net present costs were determined using a 12% discount rate over 20 years.
[b] Delucchi and Jacobson [3].
[c] Kempton and Tomic [15].
[d] Gaines and Cuenca [28].
[e] Steward [20].
[f] The energy cost for the GIV batteries are assumed to be 10% of the cost of standalone Li-ion batteries because of increased cycling, based on our estimate + $400 divided by the battery size (56 kWh, the size of the battery in the Tesla) on board vehicle costs, which will last the ∼15 year life of vehicle, from Kempton and Tomic [15] Table 5, parameter Cc.
[g] This calculation is taken from Table 5 and equations (13) and (15) [15]. For LiIon, the lifetime (L_C) is assumed to be 5000 cycles [18]. E_s is assumed to be 56 kWh which is the size of the battery pack (equivalent to Tesla Roadster). Also, the CYP is the cycles per year which is assumed to be 10. This is updated after the optimum is reached to a more realistic value. The value is then multiplied by 30% because the depth of discharge is less than 100%, degrading the batteries less. $c_d = \frac{c_{bat}}{L_C * E_S} * CPY * 30\% = \frac{\$105.96}{MWh\ year}$

[h] Capital power costs for GIV were calculated assuming it would cost $1500 for the building connections for a 15 kW battery, which converts to $100,000/MW, with a lifetime of 50 years. From Kempton and Tomic [15], Table 5.
[i] O&M power costs for GIV are considered to be zero because there is no additional maintenance due to GIV power. Maintenance is not increased due to power capability for GIV, it is calculated as proportional to energy in a separate column. The maintenance costs for controls that are particular to the GIV system, not otherwise required for the vehicle, are considered negligible.
[j] The energy cost is the cost of the steel tank, based on how many kg of hydrogen the tank can hold [20] which is converted to a $/MWh equivalent using the HHV of hydrogen. It is assumed that the steel tanks last 20 years.
[k] The power cost is assumed from the capital cost of the SOFC system and electrolyzer system taking into account the replacement cost of the stack is 30% after ten years (this replacement cost is also discounted at 10 years out). It is assumed that the power systems will last 20 years if this stack replacement is performed.
[l] Delucchi and Jacobson [3].
[m] This is calculated by scaling up a recent study of capacity potential of south facing rooftop in Newark, DE [21] and extrapolating by population to the PJM region.
[n] This is obtained for the PJM region by Baker [22]. For 2030 it is assumed the whole area out to 1 km is available.
[o] This is obtained for each state from NREL's Wind Powering America Study [23] and then multiplied by the percentage of each state in PJM as shown in the Model Parameters section. In an NREL capacity study wind sites with less than a 30% bulk capacity factor were discarded, so for an inland wind site to be considered for this simulation it had to meet the same criterion.
[p] The power electronics are mostly considered a part of the regular operation of the vehicle. The only additional electronics are the controls to regulate charge and discharge.
[q] We will limit availability of GIV storage based on the vehicle fleet. Although it would make sense to discount the fleet by the number who we guess might be participating, or also the percentage of EVs and plug-in hybrids available, here we assume 100% of the count of light vehicles in PJM in 2002. This is an upper resource limit. The total vehicle fleet per state is from NHTS 2009 survey [24]. 15 kW of storage per vehicle is assumed just as in the cost calculation for GIV.
[r] Lund and Kempton [25].
[s] Chen et al. [26].
[t] Steward [20].
[u] Assumed 6.35 mm thick 316 stainless steel at 51.7 MPa at 25 °C [27].
[v] Gaines and Cuenca [28].

Table 3
Capacity and energy of the cost-minimized mix for 2030 technology costs, using GIV for storage.

Hours covered	Power capacity (GW)			Energy produced (GWₐ)		
	30%	90%	99.90%	30%	90%	99.90%
Solar PV	0	0	16.2	0	0	2.64
Offshore Wind	0	14.4	89.7	0	6.16	38.3
Inland Wind	40.1	126	124	16.3	51.1	50.3
Fossil	61.7	56.9	28.3	15.4	2.18	0.017
Total generation	102	197	258	31.7	59.4	91.3
Storage	27.7	69.2	51.9	1.4	7.99	2.47
PJM 1999–2002		72			31.5 (average load)	

This is another important new finding. That is, our cost-minimizing model of very high penetration (90% and above)—shows that the least-cost way to cover most or all hours results in producing (or being capable of producing) 2× or more the electrical energy needed. The 99.9% criterion by definition means fossil would account for no more than 0.1% of load; Table 3 shows that the actual fossil burn required was 0.05% (0.017/31.5).

Fig. 3 shows the four-year simulation for the 99.9% case using GIV storage, which corresponds to the 99.9% columns in Table 3. The top graph, in green, is renewable generation; even with the mix of generation types renewable power generation fluctuates often, and can be seen to have lower average output in the summer than winter. Correspondingly, storage stays mostly filled in the winter months but discharges periodically during the summer months.

Table 4
Cost to make load using renewables, storage, and fossil backup, ¢/kWh in 2010 dollars.

Hours covered by all renewables (%)	Hydrogen		Central batteries		GIV	
	2008	2030	2008	2030	2008	2030
30	11	09	11	09	11	11
90	22	10	23	15	28	09
99.9	36	17	45	25	32	17

Table 5
Cost to make load as in Table 4, but also including credit for selling excess electricity to displace natural gas, (¢/kWh).

Hours covered by all renewables (%)	Hydrogen		Central batteries		GIV	
	2008	2030	2008	2030	2008	2030
30	10	09	10	09	10	11
90	19	08	20	11	23	06
99.9	31	13	39	20	26	11

Table 6
Pearson's linear correlation coefficient among the generation technologies and with load.

	Inland wind	Off-shore wind	Solar	Load
Load	0	−0.08	0.28	1
Solar	−0.18	−0.01	1	
Off-shore wind	0.46	1		
Inland wind	1			

This is intuitive because in winter, wind generation is high and electric load is low, thus storage is kept full. In summer, when wind generation is low and storage energy is depleted, fossil generators are run, albeit infrequently.

The finding noted from Table 3 for the 90% and 99.9% GIV cases, that more energy is generated than is consumed, is true for the other two storage technologies as well, and goes against the common notion that generation output should be matched to load. As examples of this common notion, Markvart proposed to match the generation energy each month to the load energy each month, adding storage as needed to balance hourly variability within the month [12]. Similarly, Denholm analyzes a combination of renewable generation, storage and load but evaluates the mix as better if over-generation is minimized, accomplished by more storage or by limiting new renewable generators [17]. Our model, of course, cares not about overgeneration, it simply makes load at minimum cost. Which criterion is right? Since our model is cost optimizing, it demonstrates that matching generation to load via more storage (per Markvart, Denholm and others) would lead to higher cost of energy than our model's selected mix. Thus, one conclusion of our study is that over-generation is preferred over more storage because excess generation is more cost-effective.

Fig. 4 shows finer detail than Fig. 3, for one challenging week starting the evening of Friday, 23 August 2002, and compares the three storage technologies. The top three graphs of Fig. 4 illustrate

Table 7
Summary of external costs used to calculate cost of fossil electricity.

|	Coal & lignite	Oil	Gas	Nuclear	Hydro	Wind
€cent/kWh 1995	5.71 (ExternE)	5.7	1.79	0.39	0.426	0.15
¢/kWh − 1995$	N/A	8.15	2.56	0.558	0.609	0.215
¢/kWh − 2010$	18 (Epstein)	11.7	3.69	0.803	0.877	0.309
PJM % generation	48	0.1	12	36	1.9	<0.01
Total PJM external cost cents/kwh			9.45			
Load following contract price cents/kwh			8			
Total cost with externalities			17.5			

Table 8
Least cost optimization results for each of the 18 RREEOM runs in the text, plus an additional one with H2 and GIV storage.

	2008 Costs			2030 Costs		
	30%	90%	99.9%	30%	90%	99.9%
Hydrogen storage						
PV GW	0	0	8.69	0	0	17.4
Offshore wind GW	0	46	91	0	7	68
Inland wind GW	50	101	111	50	124	115
Hydrogen GW	0	58	87	0	58	58
Hydrogen GWh	0	1232	2971	0	2464	2899
Average power provided to load (GWa)	19.0	30.7	31.5	19.0	31.0	31.5
Average excess power (GWa)	1.18	29.9	54.0	1.18	22.5	47.0
Central battery storage						
PV GW	0	0	32.6	0	0	50
Offshore wind GW	0	80	128	0	90	129
Inland wind GW	53	76	83	50	55	61
Li-titanate batteries GW	0	29	58	0	29	58
Li-titanate batteries GWh	0	145	435	0	145	362
Average power provided to load (GWa)	19.8	30.0	31.4	19.0	29.1	31.3
Average excess power (GWa)	1.64	35.0	62.4	1.18	31.7	56.9
GIV storage						
PV GW	0	0	0	0	0	16.2
Offshore wind GW	0	130	146	0	14	90
Inland wind GW	50	101	120	40	126	124
GIV GW	0	0	49	28	69	52
GIV GWh	0	0	382	90	891	891
Average power provided to load (GWa)	19.0	30.0	31.4	16.2	31.0	31.5
Average excess power (GWa)	1.18	66.8	79.7	0.09	26.3	59.9
H2 + GIV storage						
PV GW	0	0.0	13.8	0	0	27.9
Offshore wind GW	0	85.4	122	0	37.1	95.7
Inland wind GW	50.7	92.7	105	46.5	102	100
Storage GW	0	29.0	64.6	9.23	52.1	55.9
Storage GWh	0	459	1263	30.1	1167	1384
Average power provided to load (GWa)	19.3	30.2	31.4	18.0	30.4	31.4
Average excess power (GWa)	1.33	43.9	65.4	0.81	26.9	54.6

load versus generation without storage. Hourly load, our target, is the black wavy line, the daily load cycle over these 7 days. Generation is indicated by the filled in areas, with colors distinguishing inland wind (magenta), offshore wind (blue), and solar (yellow). The value of using diverse resources can be seen because offshore wind and solar are often generating when inland wind is not. The middle column is the optimum generation mix using central batteries. Since batteries have the highest storage cost, the cost minimization selects for higher diversity in renewable generation sources, that is, the middle top graph has more solar and offshore wind despite their higher cost, resulting in fewer times of insufficient power (insufficient power is shown as the white spaces below the black load line). (For interpretation of the references to color in this paragraph, the reader is referred to the web or PDF version of this article.)

Fig. 4's bottom row of three graphs shows how storage acts to balance generation with load. Here green shows all renewable generation that either serves load (green areas below black line) or generation that fills storage (green above black line). Olive is "excess generation," renewable generation that is not used or stored. There
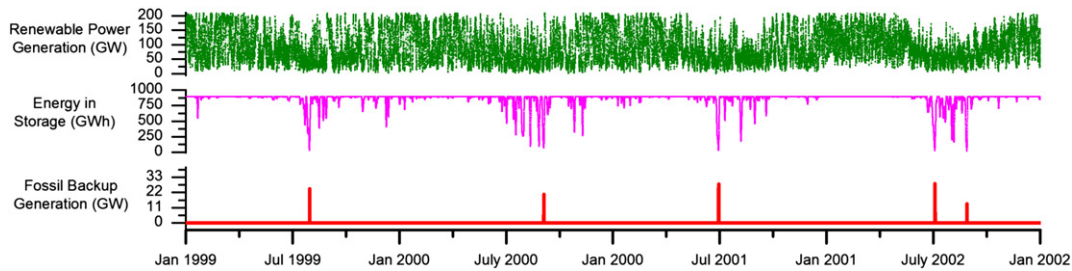
Fig. 3. Renewable generation (top), energy in storage (middle), and fossil generation (bottom) for the four-year study period in the 99.9% coverage case with GIV storage and 2030 technology costs. Scales are GW generated and GWh held in storage.

is more generation than needed to meet load at the beginning and end of the week, but storage has to provide energy in the middle of the week (gray), and as a last resort load is met with fossil generation (red). (For interpretation of the references to color in this paragraph, the reader is referred to the web or PDF version of this article.)

For the three types of storage in Fig. 4, hydrogen, central batteries, and GIV, the optimized power and energy sizes are: hydrogen, 58 GW and 2899 GWh, central batteries, 58 GW and 362 GWh, and GIV 52 GW and 891 GWh (Table 8). H2 and central batteries were at cost-optimized sizes, but GIV could not exceed 891 GWh due to lack of electric vehicles, even assuming all vehicles would be electrified and available. Another measure of storage size is, how long could storage exclusively provide average summer load (about 40 GW)—the cost minimum for the three storage types correspond to 72 h, 9 h, and 22 h. We find these to be remarkably small amounts of storage—9 to 72 h—to run the system at 99.9% reliability under all conditions encountered over four years.

We selected the week of Fig. 4 because it was one of the most challenging. During this week, fossil was dispatched to meet load in

all three storage cases. In the hydrogen case load was not met because of the power limitation from storage (lower left figure, barely perceptible red tick near the peak of day three), whereas in the centralized battery and GIV cases it is not met because of the energy limit of storage, that is, storage was empty (shown as red filling the gap from green up to load until green goes above load). Conversely, charging storage can be power limited (seen as height-limited green above load, with olive above the green), or can be energy limited, that is, storage full (only olive above the load curve, no green, until storage is drawn down again). These cases illustrate that a realistic model of large-scale storage must reflect limitations of both power and energy, as RREEOM does. (For interpretation of the references to color in this paragraph, the reader is referred to the web or PDF version of this article.)

Fig. 5 summarizes results from all 18 of our simulations. The height of bars represents GW capacity. Each cluster of bars shows one of the three percentage coverage levels, at one of the two cost years, thus six clusters of bars. Above each cluster of bars is a pie chart of energy (GWh), with each color showing how much each
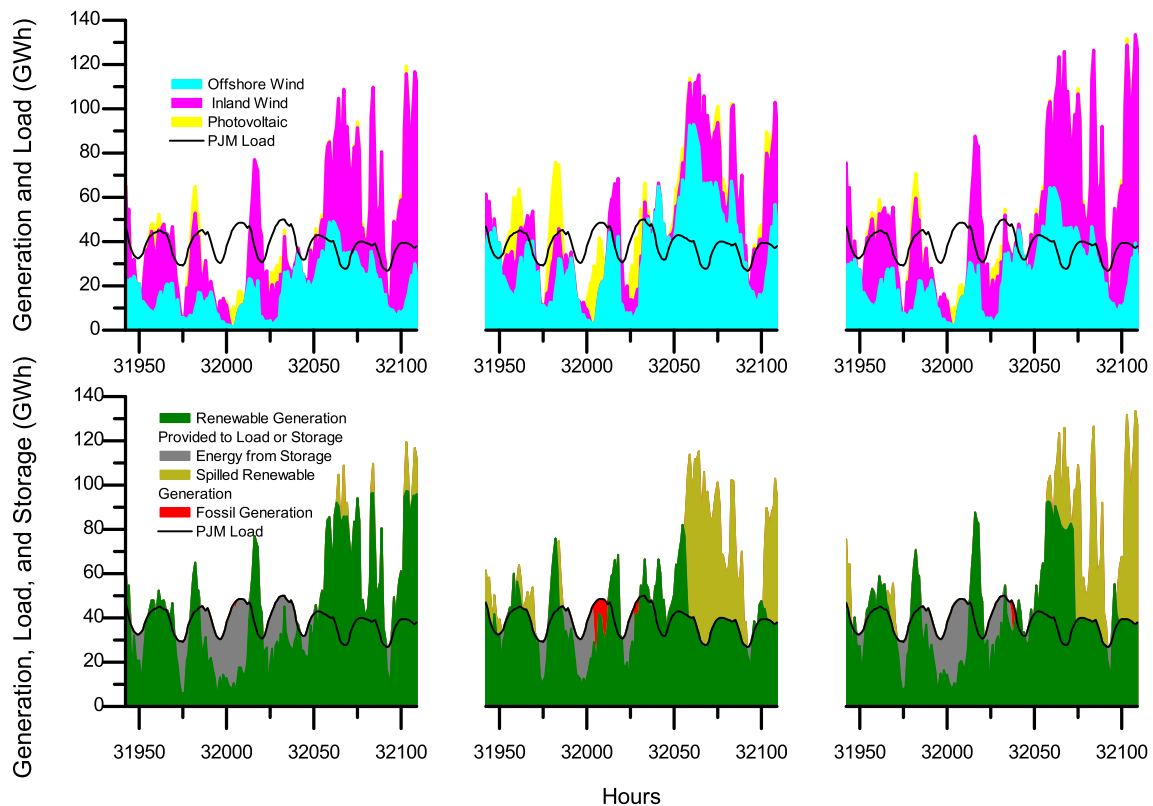
Fig. 4. Response of the optimized energy system (99.9% coverage, 2030 costs) to a challenging week for three storage technologies: hydrogen (left column), centralized battery (center column), and GIV (right column). Top row distinguishes three types of renewable generation compared to load. Bottom row distinguishes generation, storage, and spilled generation. Abscissa scale is hour of simulation.
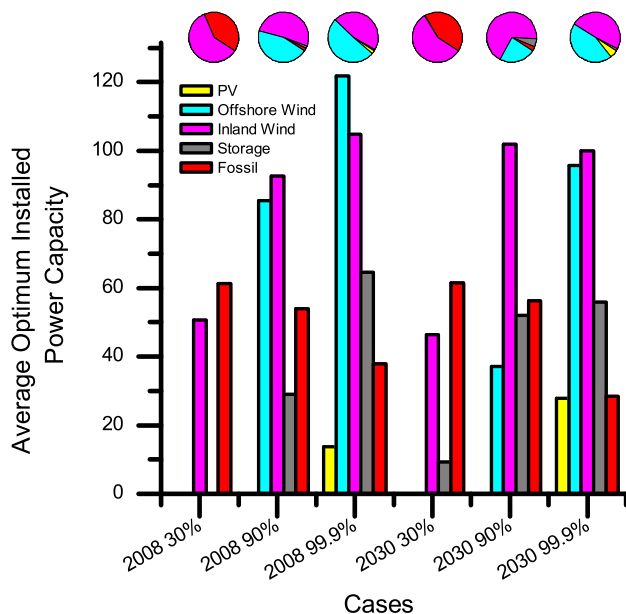
Fig. 5. Power capacity of generation and storage (bars) and source of energy used to meet load (pie charts) in all 18 RREEOM runs. Each cluster of bars (e.g. the 4 bars labeled "2008 90%") and pie chart above are an average of the three storage technologies.

Fig. 6. Natural gas consumption for the PJM region (black) compared with excess renewables generation (gray), for the GIV 2030 99.9% case. Bars are energy per month.

technology serves load. The three storage technologies are averaged to compress the graph, equivalent to deploying a mix of storage technologies. In brief, each cluster of bars shows the GW capacity and the pie above it shows the proportions of energy.

Fig. 5 demonstrates that the cost-minimized system at 30% coverage, with either 2008 or 2030 costs, has roughly equal capacity of wind and fossil, with wind generating over 60% of energy, and little or no storage. At 90% and 99.9%, renewable generation and storage increase, fossil capacity drops 10−20%, fossil energy production drops to a nearly imperceptible wedge, and virtually all electric energy comes from wind (offshore plus inland). For 99.9% coverage, comparing 2008 and 2030 costs, anticipated cheaper solar in 2030 leads to almost twice the solar capacity, enabling reduced capacity for all other generation and storage.

We found that, at high fractions of renewables, the cost minimum specifies excess renewable generation. As shown in Fig. 3, the greatest excess is in winter (more precisely, November through May). This finding leads us to analyze the use of excess electricity to displace natural gas in the residential and commercial sectors, where natural gas is mostly used for low-temperature heat. This heat use evaluation was done offline, after the cost-minimization runs, so this second use of electricity was not given any value in cost-minimization. Specifically, we converted electricity to heat based on energy content to compare the monthly match. The result, in Fig. 6, shows that monthly excess electricity corresponds to monthly residential and commercial consumption of natural gas; the match is remarkably good. This means that a more efficient economic optimization would not spill excess electricity, but rather would use it to displace natural gas. In one of our economic calculations below we credit excess electricity at the prevailing market price of natural gas. (We equivalence electricity to gas at its heat value, for example this could be done with low-capital-cost but inefficient electric resistance heat; see Appendix "Value of Excess Generation".)

The costs of electricity for these 18 optimized REEOM mixes are given in Tables 4 and 5. Table 4 gives the cost of providing all electric power from renewables, storage and fossil, with no credit for excess electricity. The ¢ kWh^{-1} in both tables can be compared
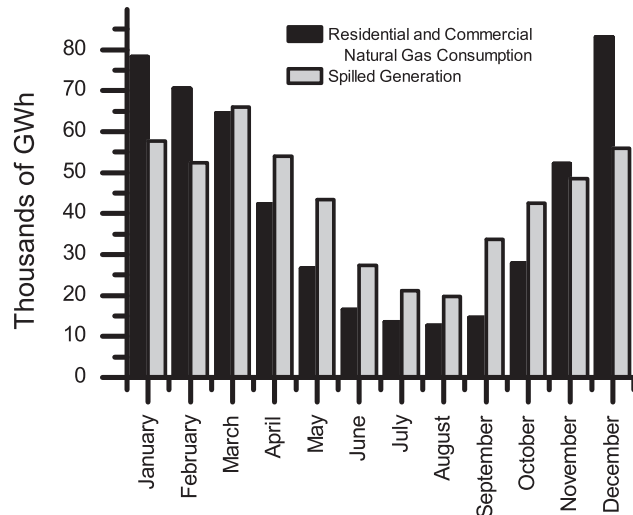
with current power costs as all are expressed in 2010 dollars. The electricity product we have modeled is "load following" power, that is, power provided from a diversity of generators with the power supplier required to continuously match load; this is more valuable than the commonly-cited baseload power costs, which cannot cover peak loads. We estimate from bilateral contracts that load following power has a wholesale market price in PJM of 8¢ kWh^{-1} for the electricity only, or total cost of 17¢ kWh^{-1} including externalities (calculated in Section A6). Comparing today's costs of 17¢ kWh^{-1} with Table 4, we find that at 2008 technology costs, 30% renewable coverage costs less than today's electricity plus externalities, whereas at 90% or 99.9% coverage, renewables cost more than today. But at 2030 technology costs, with inexpensive storage (hydrogen or GIV), renewables are at price parity at 99.9%, and are less expensive than today at 90%.

Table 5 incorporates the sale of excess electricity at times of natural gas need. Even though the electricity is sold when gas is needed, at the lower value of gas, and only at its heat value (not using a heat pump), the economics are notably improved over spilling or giving it away (per Table 4). For example, consider the low-cost case in Table 5, GIV storage and 2030 technology costs: renewables can cover 90% of the hours at only 6¢ kWh^{-1}, substantially lower than today's cost of 17¢ kWh^{-1}. For the GIV, 2030 prices case, one might ask, why is 90% the cost minimum? The answer is that costs are higher at 99.9% because substantially more renewable equipment must be purchased, and costs are higher at 30% because fossil backup costs more than renewables at 2030 costs, with all subsidies removed. On the other hand, costs for a non-optimal mix can be high. This is seen even in Tables 4 and 5 for the high-cost case of central batteries. Not shown in these tables are a very large number of more expensive ways to build a high-penetration renewables system that failed our cost-minimum tests.

We make four policy observations from Tables 4 and 5: First, at 2008 equipment costs, today's cost of electricity would be lowered by renewables covering 30% of hours (60% of energy). That is, the true cost of electricity is 1/3 lower (dropping from 17¢ to 10¢ or 11¢) at 2008 technology costs. At 2030 technology costs, we find that 90% coverage of hours (96% of energy) is the least cost for most cases. If storage is inexpensive (the GIV case) 90% coverage is much less expensive than lower fractions of renewables. The second policy observation is that aiming for 90% or more renewable energy in 2030, in order to achieve climate change targets of 80%−90%

reduction of CO_2 from the power sector, leads to economic savings, not costs. Third, the 2008 and 2030 differences show we can seek an intermediate 30% target now, and seek a 90% target later, and with the right mix, at each step the target will move toward lower costs than today's system. And fourth, noting that we find the cost-minimum using unsubsidized prices, today's market will not move to the least-cost system with current policies, because today's market is distorted by tax subsidies for renewables and nuclear, and by larger cross-sector subsidies for fossil.

6. Conclusions

Here we simulated fluctuating power input to a large regional electric system, seeking the least-cost combinations of renewable generation and storage to provide sufficient power for load. Unlike many prior studies, we do not employ storage in order to balance generation capacity more closely to load—we only care about reliably making load at the least cost.

We find that 90% of hours are covered most cost-effectively by a system that generates from renewables 180% the electrical energy needed by load, and 99.9% of hours are covered by generating almost 290% of need. Only 9–72 h of storage were required to cover 99.9% of hours of load over four years. So much excess generation of renewables is a new idea, but it is not problematic or inefficient, any more than it is problematic to build a thermal power plant requiring fuel input at 250% of the electrical output, as we do today.

At 2008 technology costs, 30% of hours is the lowest-cost mix we evaluated. At expected 2030 technology costs, the cost-minimum is 90% of hours met entirely by renewables. And 99.9% of hours, while not the cost-minimum, is lower in cost than today's total cost of electricity.

Over-generation is cost-effective at 2030 technology costs even when all excess is spilled. If excess generation displaces heating fuels, the cost is lowered further. Today's electricity is rarely used for heating because fuel cost dominates electric generation costs and energy is lost in generating electricity, so when heat is desired it is cheaper to burn fuel on site where the heat is needed. By contrast, renewable generation's primary costs are capital and the fuel is free—once built, we will want to run renewable generators whenever electricity has any value at all. Again, the cost-optimization model forces us to think about system design differently. Today we build dispatchable generation, and design for enough capacity to meet peak load plus a reserve margin. If we applied the findings of this article, in the future we would build variable generation, designing for enough capacity to make electric load for the worst hours, and as a side effect we will have enough extra electricity to meet thermal loads.

In the 99.9% case, using fossil generation to fill the gaps in the remaining 0.1% of hours (9 h year^{-1}) requires maintaining less than half of today's legacy generation capacity, with that capacity producing only 0.017% of the energy needed for load. Thus, further pollution-reduction will provide scant motivation to retire old fossil generation. However, maintaining old fossil plant may be uneconomic if rarely used, in which case, other existing mechanisms—such as demand management, interruptible rates, or preloading storage from lower capacity fossil—could be used to retire old fossil plants.

Disclosure statement

CB declares equity interest in a solar education startup. WK declares equity interest in a GIV startup. Other authors declare no conflict of interest.

Appendix A

RREEOM model

The Regional Renewable Electricity Economic Optimization Model (RREEOM) takes as inputs the costs of each type of generation or storage technology, a constraint to fully meet load for a set % of hours ("percent coverage"), a maximum limit for each resource, and hourly weather and load. The output is a single most cost-effective combination of renewable types and storage capacity, to meet the percentage coverage of hours with the given type of storage. The model does not prohibit over capacity; the capability for excess generation above load and filling storage has no negative or positive value in the optimization other than its effect on the cost. (In the real-time management of a power system, excess generation is avoided simply by turning down fuel input to thermal generators, feathering the blades of wind turbines, or switching off solar inverters; excess capacity is not a management problem, only a potential economic problem.) The model calculates renewable generation each hour from the given inputs (solar photovoltaics, offshore wind, inland wind) and subtracts that from the same hour's load. If there is excess generation it is put into storage. If instead load exceeds generation, then the model draws energy out of storage. If load exceeds generation and there is not enough in storage, the hour is counted as failing to make load from renewables. The standby losses from storage are also calculated and subtracted from energy in storage each hour. A flow chart of the simulation is in Fig. 2.

RREEOM was run using the enumerative method with 70 equally spaced-divisions per input variable i.e. all inputs were linearly sampled 70 times and all combinations of these samples were run with RREEOM. There are 5 input variables (power capacity for each of three renewable generation types, energy capacity of storage, and power capacity of storage), so 70^5, or 1,680,700,000 combinations were run. Since testing each of the 70^5 combinations against 4 years of data took approximately 0.1 s, parallel processing was essential. A 3000-processor cluster was employed, reducing each of the 18 input RREEOM cases to 168,070,000 s/3000 processors = 56,023 s = 15.5 h, times 18 different combinations = 11.6 days with 3000 processors. The electricity cost of each combination was calculated in ¢ kWh^{-1}, using 2010 dollars, as described below. Then the four years were simulated, using hourly weather, to determine if the given mix of technologies was sufficient to make hourly load the required percentage of hours. (Processing time was reduced by not running the four year simulation if the costs were higher than that of a prior successful run.)

After the optimization is run, excess generation was used to displace natural gas as a post-processing step that generated revenue and thus reduced the cost of electricity. However, the cost minimization only minimized the cost of electricity, so natural gas savings were not considered in the cost optimization.

PJM interconnection

We examine the service area of PJM Interconnection, a Transmission System Operator (TSO) spanning part of the US Eastern

Interconnect. PJM's area includes land area in 13 states and the District of Columbia, specifically: NJ (100%), PA (95%), DE (100%), MD (100%), VA (95%), WV (100%), IN (15%), OH (65%), MI (5%), IL (25%), NC (15%), KY (10%) and DC (100%). These land areas are for the PJM region today, not for our study period in 1999–2002. The earlier study period was used for load records in order to have a longer period of time (4 years) without the complication of system expansion during the model run years of our simulation. We used the contemporary PJM land areas for our renewable power output calculations, because we are using, and developing, data matched to the current PJM system, and because PJM already draws on many wind projects outside it's territory, from adjacent states. None of inland wind, solar, or offshore wind were limited by resources, so the use of a wider area had no effect of increased resource size but would have increased our model's inland wind diversity slightly over a territorial cutoff at the historic boundary. As of this writing (2012), the system has expanded to 178 GW of generation, with 0.65 GW of wind and 0.02 GW of solar operating, and applications in process to add 37.8 GW of wind and 3.6 GW of solar.[1]

Constant input values

For each technology, and for the cost years of 2008 and 2030, we provide input values for each technology in 2010 dollars. Input values are shown in Tables 1 and 2. The values in those tables are described as follows:

○ Capital cost per energy storage ($/kWh) – This is zero for generation technologies, but is important for storage technologies, for which cost per energy storage size can be the dominant cost.
○ O&M cost per energy storage throughput ($/MWh) – This expresses a MWh throughput wear factor that degrades lifetime further, on top of the standard $/MW O&M based on capacity. (This second O&M value is needed only for GIV, whose base O&M per MW is not counted since its cost is attributed to the driving function [15]; we attribute GIV O&M cost to the electric system only proportionally to the additional energy moved through the batteries to serve as grid storage.)
○ Lifetime of energy equipment (years) – Applies to storage only. Lifetime of the energy (not power) components.
○ Capital power cost ($/kW capacity) – A standard cost measure of generation, also used here for power capacity of storage. Note that capacity factor is not calculated for generation here, because the actual power output is determined hourly by measured wind speed or insolation.
○ O&M cost per unit of power capacity ($/kW year^{-1}) – The cost is per power capacity as larger facilities require more maintenance. Most data resources give O&M costs per MW capacity, so we apply it to facilities based on their MW capacity.
○ Lifetime of power equipment (years) – Applies to generation and storage – lifetime of generation, or for storage, lifetime of power conversion components. Counted as years to replacement, at which time the capital cost must be expended again.
○ Upper power limit of resource (GW) – Maximum power resource for solar and wind. For GIV, total number of cars times max power per car. (No practical power resource limit on H2 or central batteries, since the model builds as much power conversion for these as is economical.)
○ Upper energy limit of resource (GWh) – Applies only to GIV. The total number of cars times battery size per car. There is no energy resource limit for H2 and central batteries, as more can be built.

○ Round trip efficiency (dimensionless fraction) – applies only to storage
○ Storage lost over time (h^{-1}) – fraction of remaining energy lost per hour

Technologies

Inland wind – Most inland wind is generated by utility-scale (1–3 MW) turbines placed in areas of high wind speeds. The cost of wind power capacity, including the capital equipment, installation, and maintenance, were obtained from Delucchi and Jacobson [3], there is no per MWh energy production cost, as maintenance cost is calculated per power capacity per month of operation. We calculated three quantities: annual capacity factor from measured wind speed to determine likely development sites, hourly capacity factor to determine hourly power output, and upper wind resource limit for the region. All 135 meteorology stations with wind data available for the 4-year time period was collected from the National Climate Data Center [29]. Wind data at measurement height were extrapolated to 80 m hub height and power output was calculated via a commercial turbine power curve (a REpower 5M). To select stations, annual average capacity factor (CF) was calculated for each site, and stations with CF below 30% were eliminated as less likely for wind development. The resulting stations are shown in Fig. 1. The remaining stations' hourly CFs are then calculated, yielding a single CF for each hour, for the aggregate of stations. Using a single inland wind CF for each hour tremendously speeds up the iterative calculation of four years for each of the 70^5 combinations of renewables and storage, and a single hourly CF is justified since we have already simplified the problem by assuming perfect transmission. However, the stations with hourly wind speed are not adequate to know the total wind resource, which requires interpolation between weather stations and consideration of excluded land areas. The total resource calculation is available from DOE's state wind resource data [23]. We added the DOE-calculated wind capacity for each state in PJM. When appropriate we took a fraction of the state proportional to the amount of land in PJM. This yielded a total resource, expressed in MW of capacity, to use as the maximum value for RREEOM. This process resulted in a high capacity factor, about 40%, because the less economic sites were eliminated. We judge this a bit high for large-scale deployment of inland wind in this region; a more accurate approach would be to decrease the capacity factor of subsequent wind farms, after the best initial sites are developed.

Offshore wind – Offshore wind employs turbines installed on the continental shelf. Installation and maintenance costs are higher in the marine environment, but the wind is stronger and steadier. The turbines are larger (5 MW, with 10 MW planned) to reduce costs. As with inland wind, energy costs were set at zero, power capacity and O&M costs were obtained from Delucchi and Jacobson [3], also checked against Levitt et al. [30]. The hourly wind data was from NOAA buoys [29], locations shown in Fig. 1. The total resource size for the PJM region is from Baker [22]. The calculation methods are the same as for inland wind; in this case it is more reasonable to assume a uniform CF no matter how much resource is developed.

Solar – Solar photovoltaics (PV) convert light into electricity. As with wind power, capital costs and O&M costs are taken from Delucchi and Jacobson [3], cost per energy unit produced is set at zero. Calculations of generation potential draw from a study of rooftop potential for Newark, DE [21] and extrapolate to the PJM region. Hourly solar irradiation from NREL [31] for Wilmington, DE, was used to calculate solar output. Wilmington is roughly mid-latitude in the PJM region. Output power was calculated from solar inputs using NREL's PVWatts program [32].

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[1] From "Renewable Energy Dashboard," accessed May 2012 at www.green.pjm.com.

Hydrogen storage – Power into hydrogen storage is via electrolysis and compression. Power out is via a Solid Oxide Fuel Cell (SOFC). Storage is in a constructed high-pressure tank. The energy and power costs were both obtained from Steward [20]. The capital power cost in $/kW is the capital cost of the SOFC system and electrolyzer taking into account the replacement cost of the stack, which is 30% after ten years (this replacement cost is also discounted at 10 years out). A SOFC system is used because it has a lower capital cost per energy unit stored, lower maintenance cost, and higher efficiency than the other dominant fuel cell technology, protein exchange membrane. Compared to batteries, tank-based hydrogen storage also has the advantage that there are lower losses of stored energy. The disadvantages of SOFC are its low power density which makes it unfit for transportation applications (not relevant here) and the high cost of conversion equipment for moving in and out of storage. It is assumed that the power systems will last 20 years if this stack replacement is performed. The capital cost of storage is calculated from the cost per kg capacity of a hydrogen storage tank, which is converted to a $/kWh equivalent using the Higher Heating Value of hydrogen. As the technology is essentially a large steel tank, there is no size restriction assumed, and it is assumed that the steel tanks will last 20 years.

Central batteries – Lithium titanate batteries were specified because they have the longest cycle life (>5000 cycles), and the ability to charge quickly. For 2008 the costs were obtained from Burke and Miller [18] while 2030 costs were obtained from Gaines and Cuenca [28]. Power electronics prices and life-time were assumed to be the same as solar inverter costs for 2008 and 2030 taken from NREL [33]. No maximum amount of battery storage was assumed as more batteries can be built.

Grid Integrated Vehicles (GIV) – In a GIV system, an electric vehicle (here assuming lithium ion batteries) has controls to regulate the rates of charge from the grid and discharge back to the grid. Because the batteries and power electronics would already have been bought and maintained to drive the car, the costs are controls added for GIV and communications, plus increased wear on the batteries due to extra cycling. Costs are calculated according to Kempton and Tomić [15]. Energy costs are here set at 10% of the cost of standalone batteries (assuming 10% added wear due to GIV), plus $400 (on board incremental cost of controls) divided by the battery size (see below). Power costs are the cost of upgrading the building electrical system to accommodate higher power than might be used only for charging. Calculations are shown in the footnotes to Tables 1 and 2. The maximum energy capacity of the GIV storage is determined by the size of the battery and the size of the vehicle fleet in 2002 PJM. We assume that 100% of light vehicles will be EVs or PHEVs and will be made available for grid storage at times of greatest need. Assuming all cars available yield a maximum resource estimate, which could be scaled down depending on expectations of policy, market penetration and program participation. As batteries become less expensive, car buyers will want larger battery packs, so we assume per-vehicle energy storage will grow from 24 kWh for the 2008 cost to 56 kWh in 2030 (respectively, the sizes of batteries in the Nissan Leaf and the Tesla Roadster today). For the purpose of comparison, we assume the same 2002 fleet size for both cost years, because our years compare different technology costs, not the actual circumstances in each year. We do vary the size of the battery in the two years, to be realistic about vehicles for 2030. Vehicle data per state is from an NHTS 2009 survey [24] and the percentage of vehicles available in each state is given above in the PJM interconnection section. This gives a total of 15.9 million GIVs. 15 kW power capacity is assumed per vehicle for power available and for cost calculations for GIV. This power level assumes some upgrade to the building

wiring, part of the per kW cost of GIV, assuming a 50 year life consistent with building life.

In the model, whenever energy is taken out of storage, the energy available is obtained by the following: $E_L = S*R$ where E_L is the energy from storage that can meet load, S is the energy in storage to be taken out, and R is the round trip efficiency of the storage technology (can be found in Tables 1 and 2). Also each storage technology losses some of its energy content each hour. This is quantified by the following: $E_{t+1} = E_t*L$, where E_{t+1} is the new value of the energy that is stored, E_t is the current energy in storage, and L is one minus the storage loss over time (can be found in Tables 1 and 2).

Model operation

The differing mixes of generation and storage technologies are all run attempting to meet the load for the entire PJM region from 1 April 1998 through 31 December 2002, with the first months used only to initialize storage at a realistic level. The different generation resources have different time profiles. As an example, Fig. 4 suggests visually that solar has a better correlation with load than either offshore or inland wind. The load-matching advantage of solar is confirmed by the Pearson correlation coefficients seen in Table 6. Offshore wind produces more consistent output than either of the other two sources, as can also be seen in Fig. 4. The consistency of offshore wind is not visible in the correlation coefficient, although it has been previously demonstrated for the Atlantic coast [11]. These characteristics of solar and offshore wind can also be seen in the present study's cost-minimization model results, in which adding solar and offshore wind both reduce the need for storage.

We constrained the model to require that renewable generation plus storage are sufficient to provide all load for three percentages of hours—30%, 90%, and 99.9% of hours. From each of the mixes of generation and storage that successfully meet the given percentage coverage requirement, we calculate the total cost of the renewable system used to meet load. The output for each case is the least cost mix that meets the required percentage of hours.

The 99.9% criterion corresponds to 9 h per year when not all load would be covered. This is a less stringent criterion than the traditional target of "one day in 10 years" or roughly 0.03% of the time. We used 99.9% rather than 99.97% or 100% because to make a claim of 100% coverage would require a simulation run of more than 4 years, because cost may go up asymptotically as we require all hours of load for a longer sequence of years, and because we suspect it would be more cost efficient to use demand management (see below) for the few hours of shortage than to build more generation and storage. Of course, an electric system meeting our criterion of 99.9% from renewables and storage would not have lower reliability than today's electric system, because we assume that a subset of existing fossil plants will be used to meet load when the new renewables and storage are not sufficient. (In fact, by installing storage in distributed locations with appropriate switching, our proposed system would have higher reliability, because distribution failures are the most common cause of power loss.) We conservatively did not assume any use of demand management at all, whereas most large distribution utilities today have many ways of dealing with generation or transmission shortfalls—they can shed load, activate direct load reduction programs, dispatch old fossil power plants, bring in power by transmission, invoke critical peak pricing, etc. Those are likely to be more cost effective ways to meet the last 0.1% in our 99.9% case.

The RREEOM model can be thought of as calculating how much renewable electricity will be produced each hour, and how much goes to load, to storage, and out of storage. The use of renewable

electricity is sorted into the following cost categories, used for the subsequent cost calculations:

Renewable electricity uses and values:

1. Meets load immediately − credited at electricity price
2. Fills storage and replacing leaks from storage − no value
3. Drawn from storage to meet load − credited at electricity price
4. Excess generation above load and above filling of storage
   a Displaces natural gas − not used to find cost minimum, but credited at natural gas price when calculating cost of electricity in Table 5
   b Spilled or sent by transmission outside region − no value

Cost of electricity calculation

Equipment cost is one input to the model, and because the costs of these new technologies are changing rapidly, we calculate costs for two time periods. We pick the years 2008 and 2030 because the first reflects known installed costs and the second represents a time of more mature industry, with costs based on mass-production. We chose 2030 as a future comparison year also so that we could draw from, and compare results with, prior published work, specifically Delucchi and Jacobson [3].

In both 2008 and 2030 cases, the net present cost of the renewable generation plus storage is calculated as: the installation cost of all generation and storage technologies used, plus the discounted present cost (12%) of all operations and maintenance costs and equipment replacement costs (battery and power electronics) over a 20 year horizon. From present cost, we calculate the cost of electricity in $/kWh by calculating the "present energy value". That is, the lifetime amount of energy production is discounted to "present energy value", also at 12%. Discounting of future energy production in kWh is unconventional, but allows us to discount energy benefits in the future prior to knowing the future price of energy. In counting energy value, we count only kWh delivered to load, because production not delivered to load is conservatively assumed to have no value. In the cost-minimization, we did not attribute any value to remaining electricity, and the values (¢/kWh) in Table 4 are based on this calculation. After the cost minimization we separately calculate the value of selling excess electricity to displace natural gas, using the methods explained in the next section, even though realistically it could also be sold to adjacent electricity markets, or used for new non-electric end-uses such as electric cars, both with higher value than natural gas. These assumptions tend to undervalue excess electricity production in the cost minimization, so if excess electricity was given value in the cost minimization, our optimum mixes would have somewhat higher generation capacity than shown.

Cost-minimization by RREEOM is based on the above-calculated cost of renewable electricity delivered to load, including that delivered to load from storage. For the hours not fully covered by renewables or storage, some of the kWhs needed to make load are supplied by fossil generation and are charged the fossil kWh rate. To calculate the external cost of that fossil generation, we use the existing PJM generation mix, which in fact is partially nuclear, thus in PJM, our use of the word "Fossil" for traditional generation is not quite accurate. Because there is so little energy from traditional generation in our high penetration models, fill-in power probably would in fact be fossil, not nuclear. This is due to fossil generation's lower capital carrying cost and faster ramping, which are more important than fossil's disadvantages of high fuel costs and high externality costs. Although the cost of fossil electricity is not used in the optimization and we assume zero capital cost for fossil, the cost of fossil fill-in power is included in Tables 4 and 5, as it is part of the total cost per kWh of providing electricity to meet 100% of load.

The cost per delivered MWh of fossil electricity is simply calculated as present market price plus present external cost. Our comparisons with the cost of renewable electricity discount future renewable generation at 12%, and compare to the present cost and externalities of fossil fuels, a comparison that probably disadvantages renewables. Market electricity most comparable to our output is a bilateral contract price for load-following power (in which the power provider matches the needed load), not the hourly locational marginal price (LMP). Our model output matches load (at some expense) like a load-following contract, whereas LMP is primarily the cheaper baseload, and does not match load fluctuations. From familiarity with a few bilateral contracts in PJM, we take \$80 MWh^{-1} as a reasonable load-following contract price. For the higher penetration cases (90% and 99.9%), less fossil capacity is needed, so the market would shift to fewer legacy generators in operation, and we would expect attrition from the fleet of generators. Those which are not easily maintained would likely be the first to be decommissioned. Such a market might have higher costs per kWh for electricity, but lower externalities because they would be run far less frequently. As the model results show, these legacy generators will be running within a future generation mix that includes substantial storage, so—contrary to conventional thinking—fast ramp rates may not be needed as much as the ability to stay shut down efficiently for months. What we are describing is a different market for electricity, but again for simplicity, we assume the same market prices and the same externalities per kWh. We would speculate that in the 99.9% system, demand management will be more economical to cover the 9 h year^{-1} of shortfall, rather than retaining old fossil generators. Whether in the future we use old fossil or demand management has no effect on the least-cost system results, since our model considers only the cost of renewables and storage in minimizing cost to meet load.

For external costs for coal-generated electricity, we used the recent and thorough Epstein et al. study. Including all coal life cycle impacts (mining, transport, combustion products, climate change), the total mid-range external value in 2008$ is, 17.8¢ kWh^{-1} [34]. For other fuels, we used the earlier EU report "ExternE" [35], and averaged differing country values to develop a single value for each fuel, the top row in Table 7. ExternE monetizes the external costs associated with human health, ecosystems, crop output, climate change and other factors, but the values are lower than those from more thorough analyzes such as Epstein et al. [34]. (For example, ExternE calculated coal external cost as 5.71 Euro cents, or in US$2010, 11.75¢ kWh^{-1}, versus Epstein et al. 17.8¢ kWh^{-1}.) Table 7 shows the calculation for each fuel, weighted by the percentage in PJM. The coal value is based on Epstein et al., the other fuel values are from ExternE, converted to US 2010$ [35]. This calculation yields an external cost of PJM electricity of 9.45¢ kWh^{-1}, a cost born by other parties not paying for the electricity, in addition to our estimated 8¢ kWh^{-1} bilateral price paid by the buyer, for a total cost of PJM electricity of 17.45¢ kWh^{-1}.

Adding the total cost of renewables and storage to the total cost of fossil provides the total cost of electricity shown in Table 4 of the main text.

We conclude this cost section with a perspective on future cost estimation. To summarize our technology cost inputs in Tables 1 and 2 the projected 2030 capital costs are roughly half of today's capital costs, and O&M costs are roughly the same. These values are based on literature review, cited in the table notes. Of course, the precise 2030 values are not known. Based on the present rate of technical advancement and cost-reductions, and general principles of industrialization, scale-up, and learning curves, we consider the

cited 2030 costs to be reasonable estimates, not optimistic. In fact the 2030 costs do not include technology breakthroughs, which we would judge to be likely before 2030. The point of running our cost-minimization model is not to calculate a precise cost of electricity in the future, the accuracy of which is limited by uncertainties in input values. Rather, our model shows that—given lower equipment costs for renewable generation and for storage, both inevitable—a cost-optimized electricity system will have substantially more generation than needed by load, and can meet required load with storage measured in a few days rather than measured in months or seasons. Those general findings are unlikely to be changed by refinements in future cost estimates. For perspective on our finding of over-capacity being optimum, an analogy would be that, at 1980 personal computer costs, a professional worker would have one computer on his or her desktop; for those few workers who had a second computer at home, all members of the household shared it. At 2012 computer costs, the same worker may have a desktop computer at the office, a laptop in the briefcase, a cell phone in a purse or pocket, and younger members of the family may have a tablet, each of these devices a "computer". Furthermore, each computer would have three orders of magnitude more computing power than the 1980 computer from which a "one computer per family" projection might have been made. Our point is that for rapidly-evolving technologies, we must use some estimate of future costs, because projecting on the basis of present costs will obscure our understanding of the future system's configuration.

Value of excess generation

In the RREEOM cost-minimization, excess generation was not given any value. The main article explained that excess generation is well matched to natural gas demand, so as an alternative calculation of the price of electricity, we credit the excess as displacing natural gas in the commercial and residential sector. It is credited at the current retail price of natural gas in these sectors, without externalities. The displacement rate is one energy unit of electricity to directly replace one energy unit of natural gas. Technically, there are two ways of doing this. For space heating, natural gas furnaces could be replaced by resistive heating units at the point of use. While we could have assumed the more efficient electric heat pump technology for this region, resistive heat produces high temperature which can be stored for several days of heating duration using inexpensive and compact high-temperature ceramic heat storage [36]. A second technical means would be to bleed off the hydrogen storage system in order to use the hydrogen as a gaseous fuel, mixed with or displacing natural gas. Use of the hydrogen as a fuel would take advantage of the electrolyzers, not usable when storage is full, and would make good use of the buffering capacity of the hydrogen tanks, mostly full at the time of year that natural gas is mostly used. Our use of one-to-one energy unit displacement is accurate for the use of resistive heaters; the heat pump will achieve $2\times$ to $3\times$ the natural gas displacement per unit of electricity, whereas direct use of hydrogen would displace only $\sim 1/2$ due to inefficiency of the electrolyzer and pump conversions.

In order to determine how much natural gas the excess generation could displace, monthly excess generation was compared with monthly natural gas usage. An example of this comparison is shown in Fig. 6, for the 99.9% coverage case with GIV storage and 2030 costs. It can be seen that in the winter months the excess generation can replace most of the natural gas while in the summer months excess generation exceeds natural gas consumption and thus would be spilled.

Once we calculated the amount of displaced natural gas, the revenue from this displaced natural gas was calculated. The 2010 average of the residential and commercial price for the United States, $10.2 per thousand cubic feet [37] was used in this calculation and all revenue for our 20 year study period was discounted (using 12% discount rate) to the current year. This does not include the recent (2011 and 2012) drop in price, assumes no price increases for natural gas, and discounts future natural gas revenues. Arguably, we should have used wholesale natural gas prices and included externalities rather than retail and not including externalities. This present value of gas revenue was subtracted from the total cost of the renewable generation and storage system which was then used to recalculate the $/kWh of electricity (Table 5 in main text).

Summary table of output values

Table 8 shows the outputs of the 18 RREEOM simulations discussed in the text, organized by one table section per storage technology. The forth table section at the bottom is a run with both GIV and H2 as options to bring in, not discussed in the text; this had to be run at lower increment resolution or it would have required impractical amounts of computer time.

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